

Life-Cycle Greenhouse Gas Assessment of Coal and Natural Gas in the Power Sector

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Summary

Recent expansion in natural gas production has made the resource an increasingly significant component in the U.S. energy market. Further, a number of policies recently proposed and/or promulgated at the federal, state, and local levels may serve to accelerate this development. Examples of federal policies include U.S. Environmental Protection Agency air standards for power plants and vehicles, as well as bills introduced in the 114th Congress to promote increased natural gas production on federal lands, amend provisions in the tax code to incentivize natural gas production and use, and streamline the approval, permitting, and/or construction of natural gas infrastructure. Many of these proposals promote technology and infrastructure investments that could be significant and long lasting. For this reason, some stakeholders recommend a thorough analysis of the costs and benefits of these proposals as well as a full assessment of the economic and environmental impacts of increased natural gas development.

Fuel-switching strategies from other fossil fuels to natural gas have the potential to impact many segments of the general economy, including jobs, investments, infrastructure, national security, human health, safety, and the environment. A full assessment of the costs and benefits of these strategies would demand an integrated analysis across all issues. Some contend that an important component of this assessment would be a comparative analysis of the various fuels' greenhouse gas (GHG) emissions. However, reports in the scientific literature and popular press have created some confusion about the climate implications of natural gas. On the one hand, a shift to natural gas is promoted as climate change mitigation because natural gas combustion has a lower carbon dioxide (CO₂) emissions intensity than either oil or coal. On the other hand, methane, the primary constituent of natural gas, is itself a more potent GHG than CO₂, and some contend that methane leakage from the production, transport, and use of natural gas has the potential to offset the GHG emissions benefits of switching.

The net climate impact of replacing other fossil fuels with natural gas depends upon a number of analytic assumptions, including the choice of fuel, end-use sector, equipment, and processes modeled. This report presents a comparative analysis of the potential climate implications of switching from coal to natural gas in the domestic electric power generating sector. The findings include the following:

- Natural gas, when combusted at different types of existing U.S. power plants, produces anywhere from 42% to 63% of the CO₂ emissions of coal, depending upon the power plant technology.
- However, in order to more fully assess the climate impacts of a fuel employed in the power sector, analyses aim to aggregate emissions across the entire supply and utilization chain (i.e., from extraction to end use). Such analyses are referred to as life-cycle assessments (LCAs).
- Due to its potency as a GHG, methane lost to the atmosphere during the production and transport of fossil fuels (i.e., fugitive emissions) can greatly impact the life-cycle GHG emissions estimates for power generation. The Department of Energy currently estimates a fugitive emissions rate (FER) of around 1% in natural gas systems; a number of academic studies estimate rates in the range of 2%-4%.
- Further, due to its chemical composition, methane's climate impacts are significantly more pronounced in the short term as compared to the long term.
- Thus, when considering existing power plants, the average natural-gas-fired combined cycle technology produces approximately 50% of the life-cycle GHG

- emissions of coal-fired steam generation, both in the short and the long terms, given a FER of around 1%.
- However, when considering other existing natural-gas-fired technologies (e.g. single cycle) or advanced technologies, the comparative life-cycle emissions benefits of natural gas are reduced.
 - Further, when considering the possibility of higher FERs (e.g., 2%-4%), the life-cycle GHG emissions of both existing and advanced natural-gas-fired technology may be comparable to coal-fired technology in the short term and could remain within range of coal-fired technology for several decades after emissions.

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Background

Recent expansion in natural gas production—primarily the result of new or improved technologies (e.g., hydraulic fracturing and directional drilling)¹ used on unconventional resources (e.g., shale, tight sands, and coal-bed methane)²—has made natural gas an increasingly significant component in the U.S. energy market.³ Many in both the public and the private sectors have advocated for the increased production and use of natural gas because the resource is domestically available, economically recoverable, and a potential “cost-effective bridge” to a less polluting and lower greenhouse-gas-intensive economy.⁴ Many Members of Congress as well as the Obama Administration have supported this assessment.⁵

When used as a fuel, natural gas has several advantages over other hydrocarbons (e.g., oil and coal). Natural gas is more versatile; it can heat homes, fuel stoves, run vehicles, fire power plants, and, when liquefied, be exported to support the energy needs of U.S. allies and trading partners. Natural gas is cleaner-burning; it emits less carbon dioxide (CO₂) than oil or coal when used to generate electricity in a typical power plant. Further, its combustion emits no mercury (a persistent, bioaccumulative neurotoxin), virtually no particulate matter or sulfur dioxide, and less nitrogen oxides, per unit of combustion, than either oil or coal. For these reasons, pollution control measures in natural gas systems have traditionally received less attention at the federal level relative to those in other hydrocarbon industries.

However, the recent increase in unconventional natural gas production has raised a new set of questions regarding human health, safety, and environmental impacts. These concerns centered initially on water quality issues, including the potential contamination of groundwater and surface water from hydraulic fracturing and related production activities. They have since incorporated other issues, such as water management practices (both consumption and discharge), land use

¹ For a more detailed discussion on hydraulic fracturing and directional drilling technologies and their impact on natural gas production, see the section on “Hydraulic Fracturing” in CRS Report R42333, *Marcellus Shale Gas: Development Potential and Water Management Issues and Laws*, by Mary Tiemann et al.

² Unconventional natural gas resources are commonly defined as follows: Tight sands gas is natural gas trapped in low-permeability and nonporous sandstones. Shale gas is natural gas trapped in shale deposits, a very fine-grained sedimentary rock that is easily breakable into thin, parallel layers. Coal-bed methane is natural gas trapped in coal seams. These resources are referred to as “unconventional” because, in the broadest sense, they are more difficult and/or less economical to extract than natural gas extracted through “conventional” means (e.g., vertical wells).

³ U.S. natural gas production has increased each year since 2005. U.S. Energy Information Administration (EIA), “U.S. Dry Natural Gas Production,” <http://www.eia.gov/dnav/ng/hist/n9070us2a.htm>. Further, domestic natural gas consumption (including volumes delivered to the residential, commercial, industrial, transportation, and power generation sectors) has grown steadily over the past several years. EIA, “Natural Gas Consumption by End Use,” http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

⁴ For example, see statements made by Ernest J. Moniz: “In the U.S., a combination of demand reduction and displacement of coal-fired power by gas-fired generation is the lowest-cost way to reduce CO₂ emissions by up to 50%. For more stringent CO₂ emissions reductions, further de-carbonization of the energy sector will be required; but natural gas provides a cost-effective bridge to such a low-carbon future.” Ernest J. Moniz et al., *The Future of Natural Gas: An Interdisciplinary MIT Study*, June 25, 2010, p. 2.

⁵ For example, see statements made by President Barack Obama in the 2012 State of the Union address: “We have a supply of natural gas that can last America nearly 100 years, and my administration will take every possible action to safely develop this energy.” President Barack Obama, “Remarks by the President in State of the Union Address,” Washington, DC, January 24, 2012.

changes, and induced seismicity, as well as air pollution and greenhouse gas (GHG)⁶ emissions associated with natural gas production and transport activities.⁷

Recent reports in the scientific literature and popular press have created some confusion about the GHG emissions profile and the subsequent climate implications⁸ of natural gas. On the one hand, a shift to natural gas is promoted as climate change mitigation because it has a lower CO₂ emissions intensity⁹ than either oil or coal (i.e., it is commonly stated that natural gas has half the CO₂ emissions intensity of coal).¹⁰ On the other hand, methane—the primary constituent of natural gas—is itself a more potent GHG than CO₂ per unit of mass, and some contend that methane leakage from the production, transport, and use of natural gas has the potential to offset the GHG emissions benefits of switching.¹¹

Debate continues as to whether the increased production and use of natural gas brings net benefits to the general economy, including jobs, investments, infrastructure, national security, human health, safety, and the environment. To answer these questions, more analysis is necessary along each of these lines of inquiry, as greater clarity would help inform domestic policy choices. A full assessment would demand an integrated analysis across all issues. Such an analysis is not within the scope of this report. Similarly, this report does not investigate the economic or national security impacts. Nor does it attempt to assess the full environmental impacts (e.g., inclusive of the net benefits to meeting National Ambient Air Quality Standards, reducing emissions of hazardous air pollutants, improving water management and land use practices, among others).

This report focuses on one facet of the debate: the claim that the production and use of natural gas is less GHG-intensive than other fossil fuels. Specifically, it presents a comparative analysis of the potential climate implications of switching from coal to natural gas in the domestic electric power generating sector. The findings are offered to help inform the larger conversation.¹²

⁶ GHGs include CO₂, methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆), among many others. For an overview of GHGs and their impacts, see the U.S. Environmental Protection Agency (EPA), “Overview of Greenhouse Gases,” <http://www.epa.gov/climatechange/ghgemissions/gases.html>.

⁷ For a more detailed discussion on the human health, safety, and environmental issues related to unconventional natural gas production, see CRS Report R43148, *An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions*, by Michael Ratner and Mary Tiemann.

⁸ “Climate implications” refer to global warming and climate change brought on by the release of GHGs from the production and use of fossil fuels. Global warming refers to the recent and ongoing rise in global average temperature near the earth’s surface. Climate change refers to any significant change in the measures of climate lasting for an extended period of time (i.e., major changes in temperature, precipitation, or wind patterns, among other effects, that occur over several decades or longer). For more detailed information, see EPA, “Climate Change: Basic Information,” <http://www.epa.gov/climatechange/basics/>.

⁹ “Emissions intensity” refers to the emissions produced by the combustion of a fuel in relation to a unit of energy released by the combustion.

¹⁰ A detailed analysis of this statement is the objective of this report.

¹¹ See, for example, Environmental Defense Fund, “What Will It Take to Get Sustained Benefits from Natural Gas?,” <http://www.edf.org/energy/methaneleakage>; Natural Resources Defense Council, “The Role of Natural Gas in America’s Energy Mix,” June 2012, <http://www.nrdc.org/energy/files/energymixII.pdf>; and Sierra Club, “Why Move Beyond Natural Gas?,” <http://content.sierraclub.org/naturalgas/why-move-beyond-natural-gas>.

¹² This report (inclusive of **Figures 1-14**) presents emissions estimates arrived at through calculations made by the Congressional Research Service (CRS). The estimates are not observed emissions; rather, they are scenarios calculated using data provided by the EIA (i.e., industry reported power plant data); the U.S. Department of Energy, National Energy Technology Laboratory (DOE/NETL) (i.e., modeling data for advanced power plant facilities and estimates for fuel production and fuel transport emissions); and the Intergovernmental Panel on Climate Change (IPCC) (i.e., GHG radiative forcing data).

Issues for Congress

Congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable fuel resources both domestically and internationally. For some, the issue of energy policy centers on economic growth and domestic job creation; for others, it focuses on national security; for still others, it calls attention to public health, safety, and environmental concerns. For many, the recent increase in domestic natural gas production has been a panacea, and they have advocated strongly for policies to accelerate this development.

While natural gas production in the United States is driven primarily by market forces, a number of recent proposals by Congress and the Obama Administration have either explicitly or implicitly supported its development.¹³ They include, but are not limited to, the following:

- Bills that would amend various provisions in the tax code to incentivize natural gas production and use (including H.R. 905, S. 344, and S. 948);
- Bills that would support increased natural gas production on federal lands (including H.R. 70, H.R. 1330, H.R. 1616, H.R. 1647, H.R. 1663, H.R. 2295, S. 15, S. 411, S. 1196, and S. 1276);
- Bills that would streamline the approval, permitting, and/or construction of natural gas infrastructure (including H.R. 89, H.R. 161, H.R. 287, H.R. 351, H.R. 428, H.R. 1487, S. 33, S. 280, S. 1210, S. 1228, and S. 1581);
- Bills that would transfer federal natural gas regulation, guidance, or permitting to state authorities (including H.R. 866, S. 490, S. 828, and S. 1230); and
- Several proposed or promulgated rules by the U.S. Environmental Protection Agency (EPA) (including GHG standards for new and existing power plants, mercury and air toxic standards for new and existing power plants, and GHG and criteria pollutant standards for new light-, medium-, and heavy-duty vehicles).¹⁴

Many of these proposals promote technology and infrastructure investments that could be significant and long lasting. For this reason, some stakeholders recommend a thorough analysis of the costs and benefits of these proposals as well as a full assessment of the economic and environmental impacts of increased natural gas development. Some see a comparative analysis of the GHG emissions from the production and use of natural gas and other fossil fuels to be a significant component in this assessment. They argue that if natural gas is to be considered a potential “cost-effective bridge” to a less polluting and lower GHG-intensive economy, it is worth investigating the length, breadth, and destination of this bridge.

A Life-Cycle GHG Emissions Assessment of Coal and Natural Gas in the Power Sector

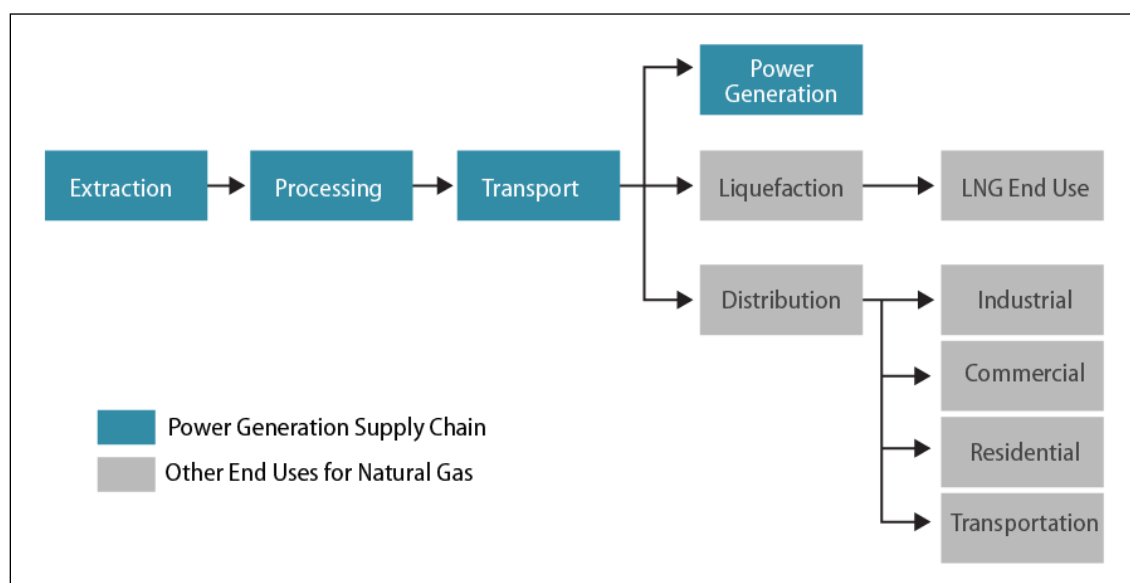
Life-cycle assessment (LCA) is an analytic method used for evaluating and comparing the environmental impacts of various products (e.g., the climate change implications of natural gas

¹³ Conversely, there have been recent proposals by Congress and the Obama Administration that would arguably slow or impede this transition.

¹⁴ For a more detailed discussion on these rulemakings, see CRS Report R43851, *Clean Air Issues in the 114th Congress: An Overview*, by James E. McCarthy.

and coal resources). In this way, LCAs are used to identify, quantify, and track emissions of CO₂ and other GHGs arising from the development of these hydrocarbon resources and to express them in a single, universal metric (e.g., CO₂ equivalent [CO₂e]¹⁵ of GHG emissions per unit of electricity generated). LCAs commonly strive to be comprehensive, and the GHG emissions profiles modeled by many are based on a set of boundaries referred to as “cradle-to-grave.” “Cradle-to-grave” assessments for fossil fuels in the power sector aim to encompass the emissions associated with the entire life-cycle of the fuel—from site preparation to the extraction, gathering, and processing of the resource; the transport of refined product to market; the combustion of the fuel in the power plant; and the transmission of the electricity to the consumer. The results of an LCA can be used to evaluate the GHG emissions intensity of various stages of the fuel’s supply chain or to compare the emissions intensity of one type of fuel or method of production to another.¹⁶

Figure 1. Natural Gas Supply Chain



Source: Congressional Research Service.

While there are many uses for natural gas (both as a fuel and as a chemical feedstock),¹⁷ this report focuses on natural gas as a fuel for the electric power generating sector. (Other end-use sectors would require different LCAs, as supply chains and combustion infrastructure would vary. See **Figure 1.**)

The methodology of this report is as follows:

¹⁵ In order to compare and aggregate different GHGs, various techniques have been developed to index the effect each GHG has to that of one unit of CO₂. This indexed value is described as a CO₂e.

¹⁶ For a more detailed discussion on the methodologies, challenges, and opportunities for using LCAs for public policy application, see S. Hellweg and Llorenç Milà i Canals, “Emerging Approaches, Challenges and Opportunities in Life Cycle Assessment,” *Science*, vol. 344, no. 6188 (June 6, 2014), pp. 1109-1113.

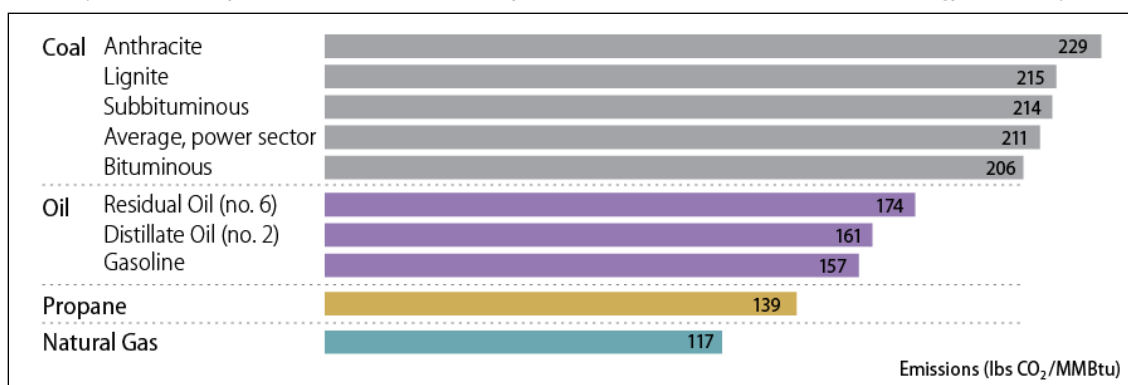
¹⁷ In 2014, the electrical power sector made up 33% of U.S. natural gas consumption delivered to consumers, followed by industrial (31%), residential (21%), commercial (14%), and transportation (1%). EIA, “Natural Gas Consumption by End Use,” May 29, 2015, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

1. The report begins by assessing the GHG emissions associated with the burning of various fossil fuels on a per-unit-of-energy basis, focusing on natural gas and coal.
2. The report then proceeds with an analysis of the GHG emissions associated with the burning of these fuels in various types of electric power generating facilities.
3. The report then expands its analysis beyond the combustion of fuels at the power plant to incorporate an LCA of the fuels' entire supply chains (i.e., inclusive of the GHG emissions released during the fuels' extraction, processing, and transport, as well as the transmission of electricity).
4. Finally, the report looks into two aspects of the assessment that have shown the greatest levels of uncertainty: (1) the fugitive emissions of natural gas during production activities, and (2) the time period over which the impacts are estimated.
5. The report ends with a cumulative summary of the findings and a discussion of policy considerations.

GHG Emissions from the Combustion of Fossil Fuels

All fossil fuels produce GHG emissions when they are combusted. The most prevalent GHG emitted from fossil fuel combustion is CO₂, which is released when the hydrocarbon molecules that make up fossil fuels are ignited in the presence of oxygen. How much CO₂ is released into the atmosphere depends upon several factors, including how much fuel is burned and the relative carbon and hydrogen content within the fuel. While there are many ways to measure and compare CO₂ emissions across different types of fuels (e.g., by the weight or by the volume of the fuel being burned), one of the most relevant methods for policy considerations is to compare the emissions produced in relation to the energy released (what is commonly referred to as the “emissions intensity” of a fuel)—for example, determining how much CO₂ is emitted by natural gas, oil, and coal in order for each to produce one British thermal unit (Btu) of energy.¹⁸ This method allows for a comparison based upon an equivalent amount of work that is being performed by each fuel.

Figure 2. CO₂ Emissions Estimates for the Combustion of Selected Fossil Fuels
(Emissions in pounds of carbon dioxide per million British thermal units of energy released)



Source: Congressional Research Service, with data from U. S. Energy Information Administration, “Documentation for Emissions of Greenhouse Gases in the United States 2008,” DOE/EIA-0638 (2006),

¹⁸ A Btu is the amount of energy it takes to heat one pound of water one degree Fahrenheit.

October 2008, Table 6-2, p. 183; and U.S. Energy Information Administration, “Documentation for Emissions of Greenhouse Gases in the United States 2005,” DOE/EIA-0638 (2005), October 2007, Tables 6-1, 6-2, 6-4, and 6-5.

Notes: EIA estimates of kilograms (kg) CO₂/million Btu (MMBtu) converted to pounds (lbs) CO₂/MMBtu.

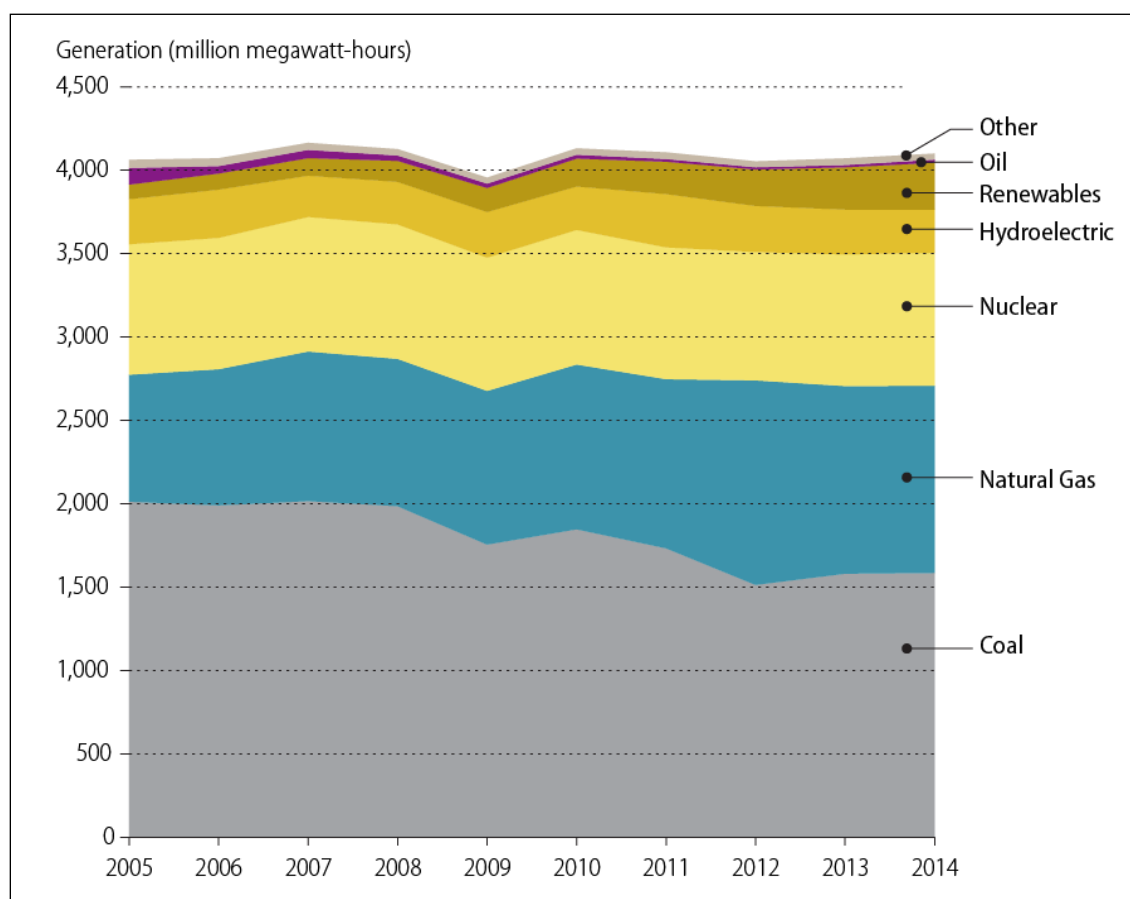
Figure 2 shows that natural gas combustion, on average, has a lower CO₂ emissions intensity than other fossil fuels.¹⁹ The primary chemical component of natural gas is methane. Methane—the simplest hydrocarbon—is made up of one carbon atom and four hydrogen atoms (CH₄). Its carbon content (and thus its CO₂ emissions potential) relative to the amount of energy it can release during oxidation is relatively low. Oil is composed of longer hydrocarbon molecules and thus has a higher carbon content. Coal’s carbon content is higher still and varies across different types of coal. Due to these varying chemical compositions, the combustion of natural gas produces approximately 56% of the CO₂ emissions per unit of energy compared to the average type of coal used commercially in the U.S. power sector.

GHG Emissions from the Combustion of Fuels at the Power Plant

Fossil fuels are combusted not simply to release energy but to use that energy to operate some type of facility or piece of equipment (e.g., a power plant, an automobile, a cook stove). Thus, the efficiency with which a piece of equipment uses a fuel’s energy will play an important role in the amount of CO₂ emitted during its operation. While there are many end uses for the energy released from the combustion of fossil fuels, this report focuses on electricity generating units (EGUs), or power plants.²⁰

¹⁹ Data from EIA, “Voluntary Reporting of Greenhouse Gases Program,” <http://www.eia.gov/oiaf/1605/coefficients.html>.

²⁰ In 2014, the electrical power sector made up 39% of U.S. primary energy consumption, followed by transportation (27%), industry (25%), and residential (12%). Fossil fuel combustion accounted for 67% of electricity generation, including coal (39%), natural gas (27%), and petroleum (1%). EIA, “Monthly Energy Review: Electricity,” March 31, 2015, <http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3>.

Figure 3. U.S. Electricity Generation by Energy Source

Source: Congressional Research Service, with data from U.S. Energy Information Administration, “Electric Power Monthly,” Table 1.1, April 27, 2015.

Notes: “Other” includes petroleum coke; blast furnace gas and other manufactured and waste gases derived from fossil fuels; and non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources. “Oil” includes distillate and residual fuel oils, jet fuel, kerosene, waste oil, and (beginning in 2011) propane.

The combustion of fossil fuels for the purpose of electricity generation accounts for approximately 67% of total U.S. electricity generation²¹ (see **Figure 3**) as well as 31% of total U.S. GHG emissions.²² Further, the combustion of fossil fuels for the purpose of electricity generation takes place in a variety of differently designed and operated power plant facilities across the United States. To calculate CO₂ emissions rates at a power plant, one must assess a facility’s “heat rate”—or what is commonly referred to as its “thermal efficiency.”²³ In other words, some power plants are more efficient at converting chemical energy from a fuel into a megawatt-hour (MWh) of electrical energy. Heat rates vary depending upon the power plant’s

²¹ EIA, “Electric Power Monthly,” Table 1.1, April 27, 2015, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01.

²² In 2013. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2013*, April 15, 2015, <http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

²³ “Heat rate” and “thermal efficiency” are terms that represent the ratio of heat energy input to electric power output. See CRS Report R43343, *Increasing the Efficiency of Existing Coal-Fired Power Plants*, by Richard J. Campbell.

design, age, operation, and maintenance practices. All other things being equal, the higher the heat rate, the lower the thermal efficiency and, thus, the more energy consumed to produce electricity.

Heat rates, thermal efficiencies, and CO₂ emissions intensities per MWh of electricity generated for various types of power plants in the United States are presented in **Table 1** and **Figure 4**. Data include (1) the average heat rates of the existing U.S. fleet of power plants, as reported by EIA,²⁴ and (2) the heat rates from a selected number of case studies performed on advanced power plant configurations, as modeled by the Department of Energy's National Energy Technology Laboratory (DOE/NETL).²⁵ For a more detailed discussion on the different types of power plant generators, both existing and advanced, see the DOE/NETL study.

Table 1. Heat Rates and CO₂ Emissions Estimates for Selected Power Plants

Fuel: Generating Unit	Heat Rate (Btu/kWh)	Thermal Efficiency	CO ₂ Emissions (lbs/MWh)
Coal: Steam Generator (average, existing) ^a	10,089	33.8%	2,125
Coal: Steam Generator (case study: subcritical) ^b	9,277	36.8%	1,888
Coal: Steam Generator (case study: supercritical) ^b	8,687	39.3%	1,768
Coal: Combined Cycle (case study: General Electric) ^b	8,756	39.0%	1,723
Coal: Combined Cycle (case study: ConocoPhillips) ^b	8,585	39.7%	1,710
Coal: Combined Cycle (case study: Shell) ^b	8,099	42.1%	1,595
Oil: Steam Generator (average, existing) ^a	10,334	33.0%	1,664
Natural Gas: Gas Turbine (average, existing) ^a	11,371	30.0%	1,330
Natural Gas: Steam Generator (average, existing) ^a	10,354	33.0%	1,211
Natural Gas: Internal Combustion (average, existing) ^a	9,573	35.6%	1,120
Natural Gas: Combined Cycle (average, existing) ^a	7,667	44.5%	897
Natural Gas: Combined Cycle (case study: Advanced F class) ^b	6,798	50.2%	804

Sources: Congressional Research Service, with data from the following:

Notes: Heat rate in British thermal units per kilowatt-hour. Thermal efficiencies calculated using the conversion 3,412 Btu/hr = 1 kW. Emissions in pounds of carbon dioxide per megawatt-hour of electricity generated. For case study power plants: heat rate, thermal efficiencies, and emissions intensities as reported by DOE/NETL-2010. For existing power plants: heat rates and thermal efficiencies as reported by EIA; emissions intensities calculated using data from **Figure 2** (including the value for coal as “average, power sector”).

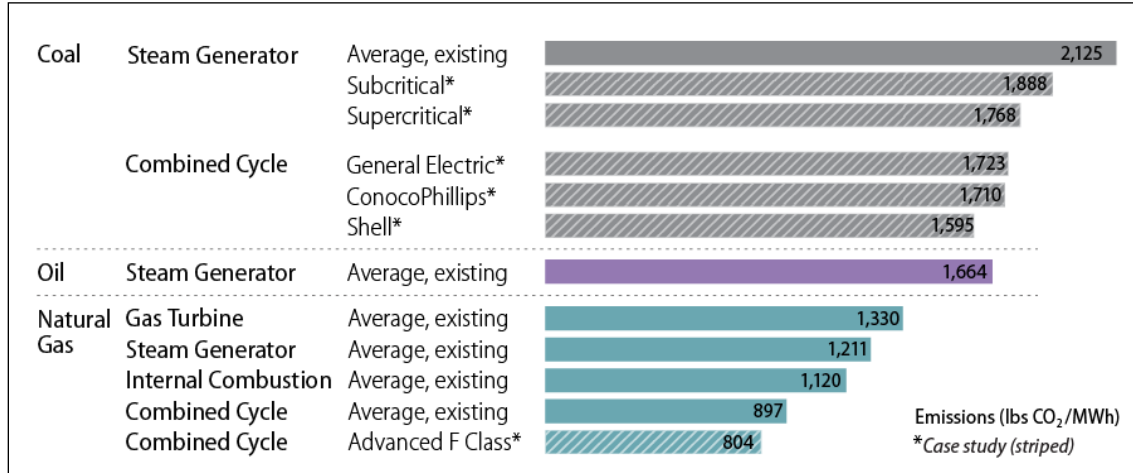
- a. U.S. Energy Information Administration, “Annual Electric Generator Report,” Form EIA-860, Table 8.2. EIA publishes industry reported emissions for the existing domestic fleet of electrical power plants averaged over categorical types of facilities.
- b. U.S. Department of Energy, National Energy Technology Laboratory, “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,” Revision 2a, September 2013, Revision 2, November 2010, DOE/NETL-2010/1397, Exhibit ES-2, p. 5. DOE/NETL estimates

²⁴ EIA, Form EIA-860, “Annual Electric Generator Report,” Table 8.2, http://www.eia.gov/electricity/annual/html/epa_08_02.html. EIA publishes industry-reported emissions for the existing domestic fleet of electrical power plants averaged over categorical types of facilities.

²⁵ DOE/NETL, “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,” Revision 2a, September 2013, Revision 2, November 2010, DOE/NETL-2010/1397, Exhibit ES-2, p. 5, http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf.

emissions for advanced power plant models. For more detail and discussion on the modeled facilities, see the report.

Figure 4. CO₂ Emissions Estimates for Selected Power Plants
(Emissions in pounds of carbon dioxide per megawatt-hour of electricity generated)



Source: Congressional Research Service, with data from U.S. Energy Information Administration, “Annual Electric Generator Report,” Form EIA-860, Table 8.2; and U.S. Department of Energy, National Energy Technology Laboratory, “Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity,” Revision 2a, September 2013, Revision 2, November 2010, DOE/NETL-2010/1397, Exhibit ES-2, p. 5.

Notes: For case study power plants: heat rate, thermal efficiencies, and emissions intensities as reported by DOE/NETL-2010. For existing power plants: heat rates and thermal efficiencies as reported by EIA, emissions intensities calculated using data from **Figure 2** (including the value for coal as “average, power sector”).

Figure 4 illustrates that the generation of one MWh of electricity from different types of U.S. natural-gas-fired power plants in 2013 produced approximately 42%-63% of the CO₂ emissions of an average coal-fired steam generator. The lower value represents emissions from a natural gas combined cycle power plant, while the higher values represent emissions from the less efficient single-cycle technologies. Further, the generation of one MWh of electricity in an advanced combined cycle natural-gas-fired power plant would produce, on average, approximately 46%-50% of the CO₂ emissions of an advanced combined cycle coal-fired generator.

While most new natural-gas-fired and coal-fired power plant construction in the United States is expected to have combined cycle or other advanced technology, the existing U.S. fleet is made up of several different types of generators. The current generation mix of the existing natural-gas-fired fleet is represented in **Table 2**. The current generation mix of the existing coal-fired fleet is almost exclusively from single-cycle steam generators.

Table 2. Natural-Gas-Fired Power Generation in 2013, by Generator Type

Generator	Net Generation (Megawatt-hours)	Percent of Total Generation
Combined Cycle	947,172,234	84%
Gas Turbine	91,272,047	8%
Steam Turbine	83,746,298	7%
Internal Combustion	2,328,424	1%

Source: Congressional Research Service, with data from U. S. Energy Information Administration, “Electricity,” Form EIA-923 (final annual 2013 detailed data), March 10, 2015.

Notes: Power plants listed on Form EIA-923 were sorted by “Prime Mover” (i.e., generator type) and included in **Table 2** if the primary fuel type reported is “natural gas.” Further, Form EIA-860 reports “nameplate capacity” (i.e., maximum rated output) by prime mover for natural-gas-fired power plants operating in 2013 to be as follows: combined cycle: 253,864 MW, 54% of capacity; gas turbine: 141,379 MW, 30% of capacity; steam turbine: 72,453 MW, 15% of capacity; and internal combustion: 2,765 MW, 1% of capacity.

GHG Emissions from the Production and Transport of Fossil Fuels

Figure 4 summarizes the CO₂ emissions intensities from the combustion of fossil fuels at a power plant. However, the combustion of fossil fuels at a power plant is not the only source of GHG emissions associated with the generation of electricity. GHG emissions associated with the extraction, processing, and transport of fossil fuels to the power plant, as well as those associated with the transmission of electricity away from the power plant, may also be of significance. These additional GHG emissions may include some quantities of CO₂ as well as methane (CH₄), nitrous oxide (N₂O), and sulfur hexafluoride (SF₆).

In order to assess the full climate impacts of a fossil fuel employed in the power sector, many analyses aim to quantify the GHG emissions released across a fuel’s entire supply and utilization chain. The following section summarizes the GHG emissions estimates for the production and transport of natural gas and coal as reported by DOE/NETL.²⁶ The “production and transport” emissions estimates are then added to the “power plant” emissions estimates to gain a more comprehensive picture of the profiles of the fuels.

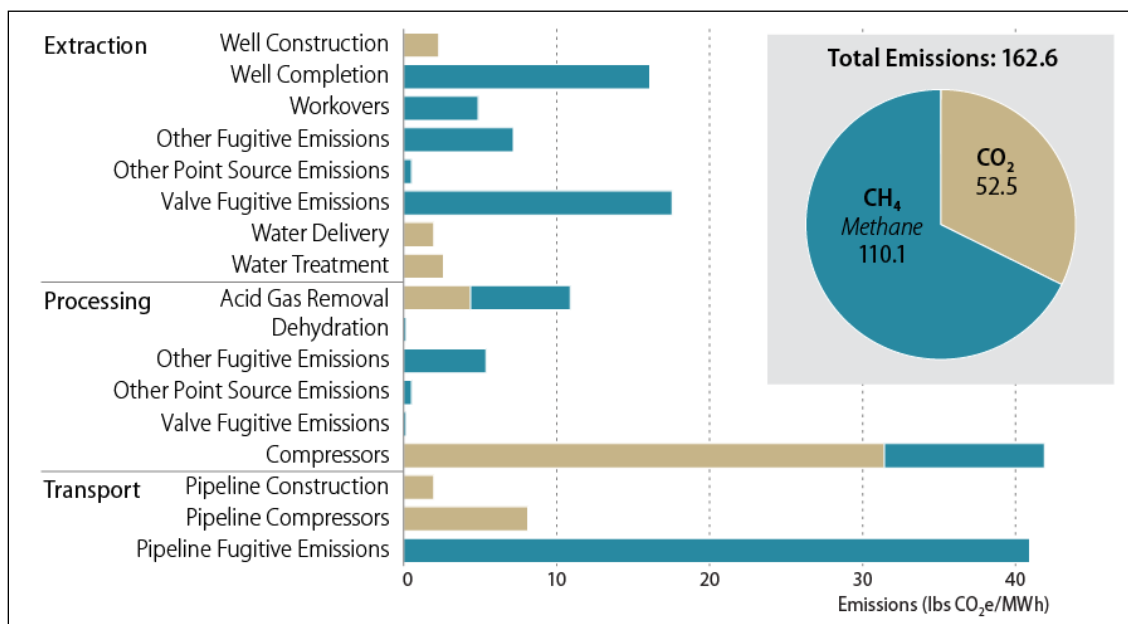
Natural Gas Production and Transport Emissions Estimates

The U.S. natural gas production and transport sector encompasses hundreds of thousands of wells and their associated equipment, hundreds of processing facilities, and over a million miles of gathering, transmission, and distribution pipelines. The sector contributes to GHG emissions in several ways, including (1) the leaking, venting, and combustion of natural gas during industry operations, and (2) the combustion of other fossil fuel resources to operate production and transport equipment. Emissions sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and gas processing and transmission equipment such as valves, compressors, dehydrators, pipes, and storage vessels. For example, the DOE/NETL estimate of the GHG emissions from production and transport activities for the electric power generating sector is shown in **Figure 5**. This estimate is for a selected natural gas source—the Marcellus Shale play in Pennsylvania. (Other sources—as well as other end-uses—would have slightly different profiles. See **Table 3** for estimates from other sources.)

²⁶ These estimates are based on data reported in DOE/NETL, “Life Cycle Analysis of Natural Gas Extraction and Power Generation,” DOE/NETL-2014/1646, May 29, 2014, <http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Life%20Cycle%20Analysis/NETL-NG-Power-LCA-29May2014.pdf>.

Figure 5. GHG Emissions Estimates for Natural Gas Production and Transport (Marcellus Shale Gas)

(Emissions in pounds of carbon dioxide equivalents per megawatt-hour of electricity generated)



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Figure 4-5, p. 38.

Notes: Modeled in 2014 for base year 2010. Estimates are for Marcellus Shale gas production and transport activities using fugitive emissions rate of 1.15% (discussed subsequently) and the 100-year index for methane's global warming potential (discussed subsequently) from the Intergovernmental Panel on Climate Change, "Climate Change 2007: The Physical Science Basis," Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. DOE/NETL-2014 emissions estimates of grams (g)/megajoule (MJ) converted to lbs/MWh based on a generator heat rate of 7,667 Btu/kWh from the **Table I** value for "Natural Gas: Combined Cycle (average, existing)."

GHG emissions from natural gas production and transport activities include, most prominently, CO₂ and methane. CO₂ is emitted as a byproduct of the burning of natural gas and other fossil fuels (e.g., diesel) during industry operations. It is released through either the flaring of natural gas for safety and health precautions²⁷ or the combustion of fuels for process heat, power, and electricity in the system (e.g., for drills, compressors, and other machinery).

Methane—the primary constituent of natural gas—is emitted when natural gas vapors are released to the atmosphere during industry operations. Every process in natural gas systems has the potential to emit methane. These emissions can be either intentional (i.e., vented) or unintentional (i.e., leaked).²⁸ Intentional emissions are releases that are designed into the system: for example, emissions from vents or blow-downs used to guard against over-pressuring, or gas-driven equipment used to regulate pressure or store or transport the resource. Conversely, unintentional emissions are releases that result from uncontrolled leaks in the system: for

²⁷ Flaring is a means to eliminate natural gas that may be impracticable to use, capture, or transport.

²⁸ EPA categorizes emissions as either "equipment leaks and vented emissions" or "combustion-related emissions." See EPA, *Inventory*.

example, emissions from routine wear, tear, and corrosion; improper installation or maintenance of equipment; or the overpressure of gases or liquids in the system.²⁹

Further, the activities and equipment used to extract, process, and transport natural gas can vary depending on the resource basin. **Table 3** presents averaged GHG emissions estimates—as reported by DOE/NETL—for the production and transport activities of eight different sources of natural gas used in the domestic power sector, as well as an average U.S. gas profile.

Table 3. GHG Emissions Estimates for Natural Gas Production and Transport Activities for the Electric Power Generating Sector

Natural Gas Category	Production and Transport GHG Emissions (lbsCO ₂ e/MWh)
U.S. Average	149.8
Onshore Conventional	156.2
Offshore Conventional	108.0
Associated	136.4
Tight	160.3
Barnett Shale	160.7
Marcellus Shale	162.6
Coal Bed Methane	140.0
Imported Liquefied	326.7

Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, “Life Cycle Analysis of Natural Gas Extraction and Power Generation,” DOE/NETL-2014/1646, May 29, 2014, Table D-1, p. D-2.

Notes: Modeled in 2014 for base year 2010. Estimates are for production and transport activities using fugitive emissions rate of 1.15% (discussed subsequently) and the 100-year index for methane’s global warming potential (discussed subsequently) from the Intergovernmental Panel on Climate Change, “Climate Change 2007: The Physical Science Basis,” Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. DOE/NETL-2014 emissions estimates of grams (g)/megajoule (MJ) converted to lbs/MWh based on a generator heat rate of 7,667 Btu/kWh from the **Table 1** value for “Natural Gas: Combined Cycle (average, existing).” “Onshore and Offshore Conventional” are defined as natural gas recovered by vertical drilling techniques. “Associated” is defined as natural gas co-extracted with crude oil. “Tight” is defined as unconventionally recovered natural gas dispersed throughout impermeable rock or non-porous sand formations. “Shale” is defined as unconventionally recovered natural gas dispersed throughout shale formations, such as the Barnett Shale region in northern Texas and the Marcellus Shale region in Pennsylvania, West Virginia, and Ohio. “Coal Bed Methane” is defined as unconventionally recovered natural gas dispersed throughout coal seams. “Imported Liquefied” is a representative scenario of liquefied natural gas imported by ocean carrier from facilities in Trinidad and Tobago, regasified in Louisiana, and entered into the U.S. natural gas transmission pipeline system.

Coal Production and Transport Emissions Estimates

Though the objective of this report is to assess the GHG emissions impacts of natural gas production and use, the potential benefits of natural gas are based on perceived advantages relative to other options, particularly coal as the status quo. The CO₂ emissions intensity related to the combustion of coal at the power plant is summarized in **Table 1**. Additional to this, an

²⁹ For a more detailed discussion on the issue of emissions in natural gas production, see CRS Report R42986, *An Overview of Air Quality Issues in Natural Gas Systems*.

analysis of the GHG emissions associated with the extraction and transport of coal is necessary to allow for a more meaningful comparison. **Table 4** outlines two major U.S. coal resources: Illinois No. 6 underground-mined bituminous and Powder River Basin surfaced-mined subbituminous. DOE/NETL reports emissions estimates for the production and transport of these two resources and uses these values to build an average U.S. coal profile.

Table 4. GHG Emissions Estimates for Coal Production and Transport Activities

Coal Category	Production and Transport GHG Emissions (lbsCO ₂ e/MWh)
U.S. Average	115.0
Powder River Basin Surface-Mined Subbituminous	30.0
Illinois No. 6 Underground-Mined Bituminous	200.0

Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, “Life Cycle Analysis of Natural Gas Extraction and Power Generation,” DOE/NETL-2014/1646, May 29, 2014, Figure 4-3, p. 36, and Table D-3, p. D-6.

Notes: Modeled in 2014 for base year 2010. Estimates are for production and transport activities for Illinois No. 6 underground-mined bituminous and Powder River Basin surfaced-mined subbituminous with coal-bed methane capture using the 100-year index for methane’s global warming potential (discussed subsequently) from the Intergovernmental Panel on Climate Change, “Climate Change 2007: The Physical Science Basis,” Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. DOE/NETL-2014 emissions estimates of pounds (lbs)/million British thermal units (MMBtu) converted to lbs/megawatt-hour (MWh) based on a generator heat rate of 10,089 Btu/kWh from the **Table 1** value for “Coal: Steam Generator (average, existing).”

GHG emissions from the production and transport of coal are summarized in **Table 4**. Emissions are associated with the following activities: (1) land use changes due to removal of overburden, (2) the operation of major equipment and mining components (e.g., drills, shovels, trucks, continuous miners and longwall mining systems, conveyor belts, stackers/reclaimers, crushers, coal cleaning equipment, silos, wastewater treatment, and shuttle car systems), and (3) the diesel-powered unit trains used to transport coal from the mining site to the power plant.

As with natural gas, coal extraction activities can release methane emissions. Different coal resource basins are characterized by different levels of specific methane content. Also, in some instances (e.g., Powder River Basin surface mining), extraction of coal-bed methane prior to mining of the coal seam results in a net reduction of the total amount of methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market. The DOE/NETL-2014 study reports the average range of methane emissions from coal production and transport activities to be anywhere from four to 504 standard cubic feet per ton of coal produced.

Life-Cycle GHG Emissions Estimates for the Power Sector

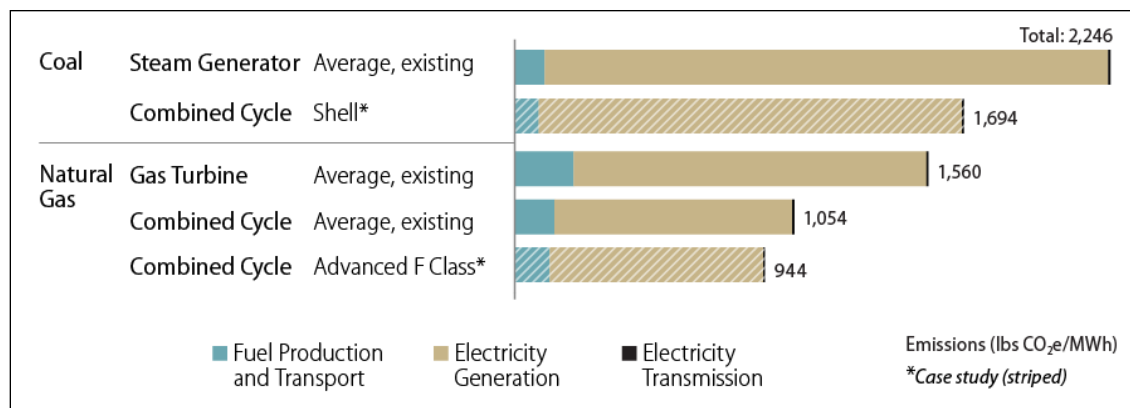
Figure 6 presents life-cycle GHG emissions estimates for selected power plants in the United States. These estimates include emissions from the combustion of the fuel at the power plant (i.e., from **Table 1**), the emissions from the extraction, processing, and transport of the fuel resources (i.e., from **Table 3** and **Table 4**), and the emissions from the transmission of the electricity generated.³⁰ The figure shows that production and transport emissions account for approximately

³⁰ Emissions during electricity transmission result primarily from land use changes. See DOE/NETL-2014.

5% of the total life-cycle emissions for coal-fired power generation and 15% of the total life-cycle emissions for natural-gas-fired power generation.

Figure 6. Life-Cycle GHG Emissions Estimates for Selected Power Plants

(Emissions in pounds of carbon dioxide equivalents per megawatt-hour of electricity generated)



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Tables D-1 and D-3, pp. D-2-D-6; U.S. Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," Revision 2a, September 2013, Revision 2, November 2010, DOE/NETL-2010/1397, Exhibit ES-2, p. 5; U.S. Energy Information Administration, "Annual Electric Generator Report," Form EIA-860, Table 8.2; and Intergovernmental Panel on Climate Change, "Climate Change 2007: The Physical Science Basis," Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

Notes: Power plant data from **Table 1**; fugitive emissions rate of 1.15% (discussed subsequently); global warming potential of 25 for methane (discussed subsequently).

Further, **Figure 6** illustrates that the generation of one MWh of electricity in an average U.S. natural-gas-fired combined cycle power plant in 2013 produced approximately 47% of the life-cycle GHG emissions of a coal-fired steam generator. However, the generation of one MWh of electricity in an average U.S. gas turbine power plant in 2013 produced approximately 70% of the life-cycle GHG emissions of a coal-fired steam generator. Further, when comparing examples of the most efficient, advanced power plant technologies (as modeled by DOE/NETL-2010), the generation of one MWh of electricity in an advanced combined cycle natural-gas-fired power plant would produce approximately 56% of the life-cycle GHG emissions of an advanced combined cycle coal-fired power plant.

Based on these initial findings, a switch from coal to natural gas in the existing fleet of U.S. power plants can realize a 50% reduction in GHG emissions (i.e., the reduction commonly stated) if the switch is from existing coal-fired steam generators to existing natural-gas-fired combined cycle generators. However, these estimates are based on certain assumptions about the GHG emissions profiles of coal and natural gas production and transport activities. The remainder of this report focuses on a more detailed analysis of these input assumptions.

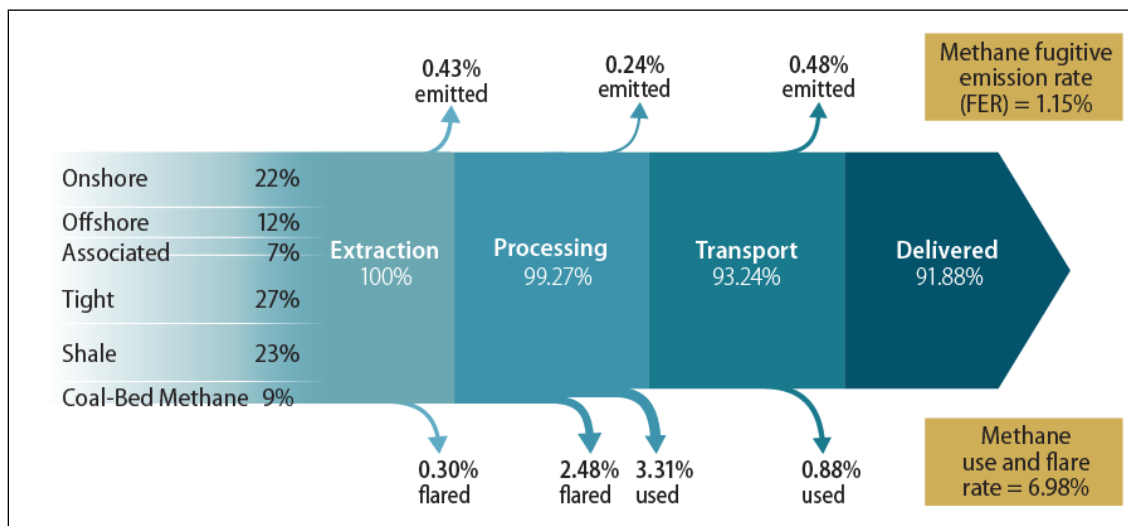
The Role of Methane's FER

One of the more significant variables in understanding the climate implications of fossil fuel use in the power sector is the role that methane emissions play in the overall assessment. Methane is commonly understood to be a more potent GHG than CO₂: Current indices report methane emissions per unit mass to be approximately 25 times more potent than CO₂ emissions when

averaged over the first 100 years after its release.³¹ Due to this potency, the amount of methane lost to the atmosphere during the production and transport of fossil fuels can greatly impact the life-cycle GHG emissions estimates for power generation.

Unlike with CO₂, where emissions are reported using well-tracked energy statistics,³² methane is emitted to the atmosphere primarily through fugitive releases of the gas (i.e., emissions that are leaked or vented from fossil fuel infrastructure). By definition, fugitive emissions are diffuse, transitory, and elusive. Thus, one of the greater difficulties in understanding the impacts of methane on the sector is acquiring comprehensive and consistent emissions data.

Figure 7. Methane Emissions and Use During Natural Gas Production Activities



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Figure 4-3, p. 36.

Note: Modeled in 2014 for base year 2010.

Figure 7 illustrates an estimate done by DOE/NETL of the quantities of methane that are lost or consumed during natural gas production and transport activities for the power sector (i.e., **Figure 7** is a representation of the methane emissions data included in **Table 3**). Using reporting from EIA³³ and EPA, the DOE/NETL study calculates rates for (1) the fugitive release of methane from natural gas systems, and (2) the flaring and/or use of methane in natural gas systems, in relation to the quantity of natural gas produced.³⁴ According to the study, the FER for natural gas systems

³¹ Methane's potency as a GHG vis-à-vis CO₂ is discussed in greater detail in the next section.

³² According to EPA's *Inventory*, over 94% of CO₂ emissions in 2012 were attributed to fossil fuel combustion for energy use. Further, much of the remaining CO₂ emissions arise from similar combustion processes in other industries.

³³ EIA, "U.S. Natural Gas Gross Withdrawals and Production," http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

³⁴ EIA defines "produced" natural gas as "the volume of natural gas withdrawn from reservoirs less (1) the volume returned to such reservoirs in cycling, repressuring of oil reservoirs, and conservation operations; less (2) shrinkage resulting from the removal of lease condensate; and less (3) nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Volumes of gas withdrawn from gas storage reservoirs and native gas, which has been transferred to the storage category, are not considered production. Flared and vented gas is also considered production. (This differs from "Marketed Production," which excludes flared and vented gas.)" EIA, "U.S. Natural Gas Gross Withdrawals and Production," http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

in 2010 was 1.15%, and the flaring and/or use rate was 6.98%. These estimates are averages, and they are dependent on a variety of input data that are both sensitive to and impacted by the uncertainty of key parameters, including (1) the use and emission of natural gas along the pipeline transmission network; (2) the rate of natural gas emitted during unconventional gas extraction processes, such as well completion and workovers; and (3) the lifetime production rates of wells.³⁵

The DOE/NETL study bases its calculations in part on emissions data provided by EPA. EPA reports methane emissions for the source category “natural gas systems” annually as a part of the agency’s *Inventory of Greenhouse Gas Emissions and Sinks*.³⁶ EPA’s *Inventory* is based on the use of measurement methodologies that employ commonly accepted emissions factors (i.e., formulas) and activity levels (i.e., equipment counts) to calculate aggregate emissions estimates for all source categories. That is, the *Inventory* is determined annually by calculations, not direct measurement.³⁷

Table 5 shows annual emissions estimates from EPA’s *Inventory*. The table presents data as they were estimated initially by the *Inventory* and not as they were revised in successive years. Thus, the table illustrates the evolution of EPA’s measurement methodology as much as it presents changes in annual emissions from the industry. As shown in **Table 5**, EPA estimates that methane releases by “natural gas systems” accounted for 1.28% of produced natural gas in 2013 (i.e., this estimate is an average for all end-use sectors, not just the electrical power generating sector).³⁸

Table 5. Methane Fugitive Emissions Rates (FER) as a Percentage of Reported Natural Gas Production

(Emissions by year as originally reported by EPA’s *Inventory*)

Emissions	1996	2008	2009	2010	2011	2012	2013
Methane Emissions Total (bcf) ^a	311	238	547	532	357	321	332
U.S. Natural Gas Production (bcf) ^b	20,084	21,279	21,813	22,548	24,245	25,496	25,951
Methane Fugitive Emissions Rate (FER)	1.55%	1.12%	2.51%	2.36%	1.48%	1.26%	1.28%

Source: Congressional Research Service, with data from the following:

³⁵ For more discussion on the uncertainty analysis, see DOE/NETL-2014, pp. 34-41.

³⁶ According to EPA’s *Inventory*, “natural gas systems” are defined to include operations in the production of crude oil and natural gas as well as the processing, transmission, and distribution of natural gas. For both operational and regulatory reasons, the industry is commonly separated into four major sectors: (1) crude oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution. Petroleum refining (i.e., crude oil processing after the production phase) is classified as another industry sector for regulatory purposes, as is electrical generation at power plant facilities. The natural gas supply chain for the electrical power generating sector is one aspect of “natural gas systems” and generally would not include the natural gas distribution sector.

³⁷ A discussion of the advantages and disadvantages of various measurement methodologies (including direct measurement, calculations by emissions factors and activity levels, and atmospheric studies) can be found in CRS Report R43860, *Methane: An Introduction to Emission Sources and Reduction Strategies*.

³⁸ EPA’s *Inventory* includes the natural gas distribution sector in addition to the production, processing, transmission and storage sectors that would be assessed for power generation (see **Figure 1**). The distribution sector includes utility scale pipelines and metering stations between the city gate and individual end users. EPA estimates that the distribution sector accounts for 21% of total methane emissions from natural gas systems.

Notes: EPA emissions estimates of kiloton (metric) (kt) converted to billion cubic feet (bcf) with conversion factor of 1 kt = 0.051921 bcf.

- a. U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks.
- b. U.S. Energy Information Administration, "U.S. Natural Gas Gross Withdrawals and Production."

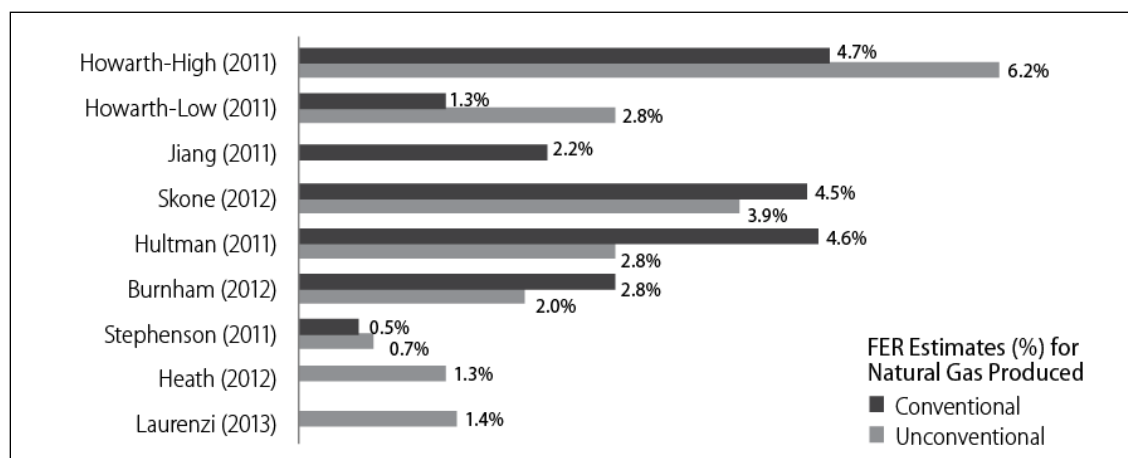
In addition to the estimates from DOE/NETL and EPA, a number of academic studies have published emissions estimates for natural gas systems. Each study employs varied choices of data sources, system boundaries, modeling approaches, and inclusion or exclusion of specific activities; thus, all return slightly differing estimates. A harmonization of several of the more prominent studies was conducted by researchers at DOE's Joint Institute for Strategic Energy Analysis and National Renewable Energy Laboratory.³⁹ The harmonized FER estimates are presented in **Figure 8**. The studies estimate FER for both conventional and unconventional natural gas resources for use in the electrical power generating sector. The findings range from 0.53% to 6.20%, and while the sample size is small, the mean value returned by the studies is 2.78%. The range within one standard deviation (i.e., a FER of approximately 2.0%-4.0%) reflects estimates for natural gas systems as reported recently by other harmonized studies⁴⁰ as well as several large-scale atmospheric measurement studies.⁴¹

The reported values in **Figure 6** reflect a FER of 1.15%. The range of FER discussed above (i.e., 1.15% from DOE/NETL and 2%-4% from the harmonized academic sources) is used as a representative estimate for the remainder of this report. (While additional academic, industry, and governmental studies exist for estimates of fugitive emissions rates, this report proceeds with the use of the DOE/NETL and DOE/JISEA harmonized estimates.)

³⁹ Garvin A. Heath et al., "Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation," *Proceedings of the National Academy of Sciences of the United States of America*, vol. 111, no. 31 (August 5, 2014), E3167-E3176, <http://www.pnas.org/content/111/31/E3167.abstract>. See also Supplementary Material, Dataset S3, <http://www.pnas.org/content/suppl/2014/07/16/1309334111.DCSupplemental>.

⁴⁰ For example, "Methane emissions from U.S. and Canadian natural gas systems appear larger than official estimates." Adam Brandt et al., "Methane Leaks from North American Natural Gas Systems," *Science*, vol. 343, no. 6172 (February 14, 2014), pp. 733-735, <http://www.sciencemag.org/content/343/6172/733.summary>.

⁴¹ For example, "The modeling suggests an upper bound global average FER of 5% during 2006–2011, and a most likely FER of 2–4% since 2000, trending downward." Stefan Schwietzke, "Natural Gas Fugitive Emissions Rates Constrained by Global Atmospheric Methane and Ethane," *Environmental Science and Technology*, vol. 48, no. 14 (2014), pp 7714–7722, <http://pubs.acs.org/doi/abs/10.1021/es501204c>. "Results show that current inventories from the US Environmental Protection Agency (EPA [2013 inventory for 2011 emissions]) and the Emissions Database for Global Atmospheric Research underestimate methane emissions nationally by a factor of ~1.5 and ~1.7, respectively." Scott Miller, "Anthropogenic Emissions of Methane in the United States," *Proceedings of the National Academy of Sciences of the United States of America*, vol. 110, no. 50 (November 25, 2013), <http://www.pnas.org/content/early/2013/11/20/1314392110.abstract>.

Figure 8. Fugitive Emissions Rates (FER) from Selected Published Studies

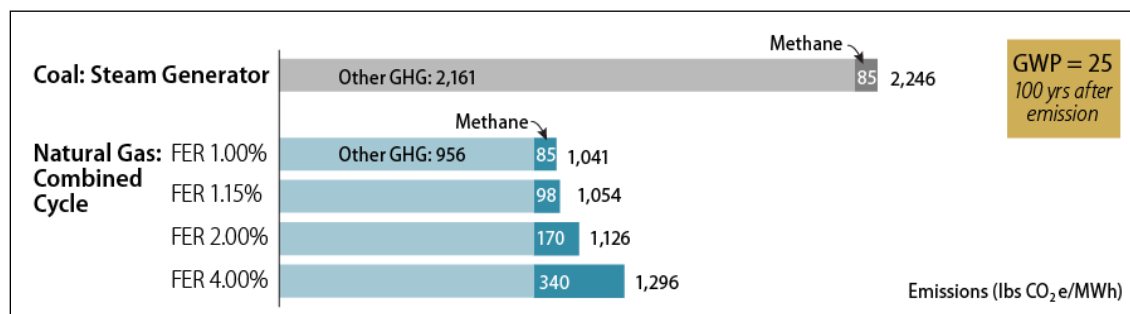
Source: Congressional Research Service, with data from Garvin Heath et al., “Harmonization of Initial Estimates of Shale Gas Life-Cycle Greenhouse Gas Emissions for Electric Power Generation,” *Proceedings of the National Academy of Sciences of the United States of America*, vol. 111, no. 31 (August 5, 2014), E3167-E3176, Supplementary Material, Dataset S3.

Notes: Studies include R. W. Howarth, R. Santoro, and A. Ingraffea, “Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations,” *Climate Change*, vol. 106, no. 4 (2011), pp. 679-690; M. Jiang et al., “Life-Cycle Greenhouse Gas Emissions of Marcellus Shale Gas,” *Environmental Research Letters*, vol. 6 (2011), p. 034014; T. Skone et al., “Role of Alternative Energy Sources: Natural Gas Technology Assessment,” DOE/NETL, DOE/NETL-2012/1539, 2012; N. Hultman et al., “The Greenhouse Impact of Unconventional Gas for Electricity Generation,” *Environmental Research Letters*, vol. 6, no. 4 (2011), p. 044048; A. Burnham et al., “Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum,” *Environmental Science and Technology*, vol. 46, no. 2 (2012), pp. 619-627; T. Stephenson, J. E. Valle, and X. Riera-Palou, “Modeling the Relative GHG Emissions of Conventional and Shale Gas Production,” *Environmental Science and Technology*, vol. 45, no. 24 (2011), pp. 10757-10764; G. Heath, J. Meldrum, and N. Fisher, “Life-Cycle Greenhouse Gas Emissions from Barnett Shale Gas Used to Generate Electricity,” in *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity*, eds. J. Logan et al., NREL/TP-6A50-55538 (Golden, CO: National Renewable Energy Laboratory, 2012); and I. J. Laurenzi and G. R. Jersey, “Life-Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas,” *Environmental Science and Technology*, vol. 47, no. 9 (2013), pp. 4896-4903.

Life-Cycle GHG Emissions Estimates, with Selected FER

Figure 9 presents life-cycle GHG emissions estimates for existing coal-fired and natural-gas-fired power plants, highlighting the contributions that fugitive methane emissions make in both instances when averaged over the first 100 years after their release.

Figure 9. Life-Cycle GHG Emissions Estimates with Selected FER, 100-Year Average
(Emissions in pounds of carbon dioxide equivalents per megawatt-hour of electricity generated)



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, “Life Cycle Analysis of Natural Gas Extraction and Power Generation,” DOE/NETL-2014/1646, May 29, 2014, Tables D-1 and D-3, pp. D-2-D-6; U.S. Energy Information Administration, “Annual Electric Generator Report,” Form EIA-860, Table 8.2; and Intergovernmental Panel on Climate Change, “Climate Change 2007: The Physical Science Basis,” Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

Notes: Global warming potential of 25 for methane (IPCC, AR4 2007, 100-year). The conceptual presentation of these data was introduced in Stefan Schwietzke, “Natural Gas Fugitive Emissions Rates Constrained by Global Atmospheric Methane and Ethane,” *Environmental Science and Technology*, vol. 48, no. 14 (2014), pp 7714-7722.

Further, **Figure 9** illustrates the impacts that several different values for FER in the natural gas production and transport sector have on the overall life-cycle emissions estimates of natural-gas-fired power generation. Notably, if the FER is close to the 1.15%, as currently estimated by DOE/NETL, the generation of one MWh of electricity in an average U.S. natural-gas-fired combined cycle power plant in 2013 would produce approximately 47% of the life-cycle GHG emissions of a coal-fired steam generator. If the FER were in the range of 2%-4%, as estimated by several academic sources, natural gas could produce 50%- 58% of the life-cycle GHG emissions of coal. (These estimates represent the impacts that emissions have when averaged over the first 100 years after their release. The impacts can change depending upon the time frame assessed, as discussed further in the next section.)

The Role of Global Warming Potentials (GWP)

While methane is understood to be a more potent GHG than CO₂, its characteristics as a radiative forcing agent differ from CO₂ in several ways. When methane is first released into the atmosphere, its capacity to trap heat is approximately 100 times that of CO₂. However, methane has a shorter lifespan in the atmosphere, degrading in about 12 years compared to approximately 1,000 years for CO₂. Because of these differences, methane’s impacts are commonly measured against CO₂ through the use of an index referred to as “Global Warming Potential” (GWP). GWP is a measure of the total energy that an equivalent mass of gas absorbs compared to CO₂ over a particular period of time (generally reported as 20, 100, and 500 years). According to the current index used by EPA, the same amount of methane emissions by mass is approximately 25 times more potent than CO₂ emissions when these impacts are averaged over the first 100 years after their release. This value is relevant when looking at the long-term benefits of eliminating a temporary source of methane emissions versus a CO₂ source.

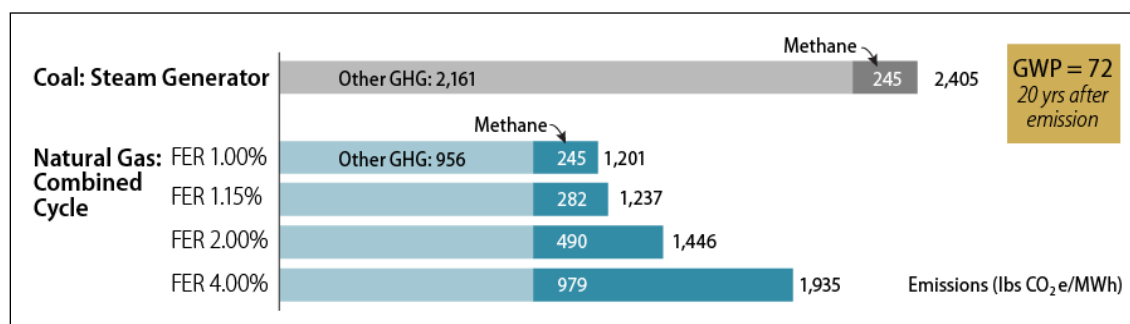
However, when averaged over the first 20 years, the GWP for methane is estimated to be 72. This figure is arguably more relevant to the evaluation of methane emissions over the next two or three decades (which some contend to be most critical in discussing whether the world can reach the consensus objective of limiting the long-term increase in average surface temperatures to 2

degrees Celsius (°C)).⁴² Because the cost-benefit analysis of climate policy choices can vary greatly depending upon the assessed time frame, many studies—including this report—present emissions estimates for both the 100-year and 20-year scenarios.

Life-Cycle GHG Emissions Estimates, with Selected GWP

Considering a 20-year time frame, the life-cycle GHG emissions estimates for existing coal-fired and natural-gas-fired power plants are represented in **Figure 10**.

Figure 10. Life-Cycle GHG Emissions Estimates with Selected FER, 20-Year Average
(Emissions in pounds of carbon dioxide equivalents per megawatt-hour of electricity generated)



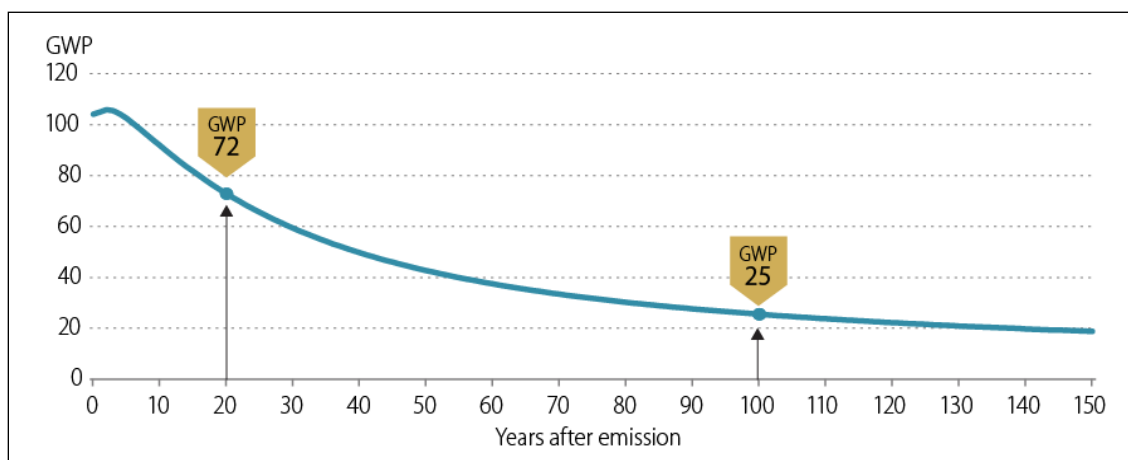
Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Tables D-1 and D-3, pp. D-2-D-6; U.S. Energy Information Administration, "Annual Electric Generator Report," Form EIA-860, Table 8.2; and Intergovernmental Panel on Climate Change, "Climate Change 2007: The Physical Science Basis," Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

Notes: Global warming potential of 72 for methane (IPCC AR4 2007, 20-year). The conceptual presentation of these data was introduced in Stefan Schwietzke, "Natural Gas Fugitive Emissions Rates Constrained by Global Atmospheric Methane and Ethane," *Environmental Science and Technology*, vol. 48, no. 14 (2014), pp 7714-7722.

Figure 10 illustrates the impacts that several different values for FER in the natural gas production and transport sector have on the overall life-cycle emissions estimates of natural gas power generation when averaged over the first 20 years after their release. Notably, if the FER is close to the 1.15%, as currently estimated by DOE/NETL, the generation of one MWh of electricity in an average U.S. natural-gas-fired combined cycle power plant in 2013 would produce approximately 51% of the life-cycle GHG emissions of a coal-fired steam generator. If the FER were in the range of 2%-4%, as estimated by several academic sources, natural gas could produce 60%- 80% of the life-cycle GHG emissions of coal. The difference between the 20-year and 100-year estimates is not insignificant, and this range highlights the importance that time frames have on life-cycle GHG emissions assessments.

Figure 9 and **Figure 10** capture snapshots of the averaged impacts of methane at the 100-year and the 20-year marks, respectively. A full range of methane's GWP is charted in **Figure 11**, which shows the averaged impacts of methane vis-à-vis CO₂ through the first 150 years after its release.

⁴² For an example of this argument, see the International Energy Agency, "Golden Rules for a Golden Age of Gas," November 12, 2012, http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf.

Figure 11. Methane's Global Warming Potential (GWP) Curve, IPCC 2007

Source: Congressional Research Service, with data from Intergovernmental Panel on Climate Change, "Climate Change 2007: The Physical Science Basis," Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

It should be noted that the scientific community periodically revises the reported values of GWP as a result of ongoing research. EPA currently employs GWP values for methane that were accepted by parties to the United Nations Framework Convention on Climate Change (UNFCCC) as they were presented in the Intergovernmental Panel on Climate Change (IPCC) *Fourth Assessment Report 2007* (AR4).⁴³ The AR4 lists methane's GWP as 25 and 72 over a 100-year and a 20-year time horizon, respectively. The AR4 GWP values are reflected in the calculations for **Figure 4** through **Figure 9** of this report.⁴⁴

However, in September 2013, the IPCC released its *Fifth Assessment Report 2013* (AR5).⁴⁵ AR5 lists methane's GWP as 34 and 86 over a 100-year and a 20-year time horizon, respectively. While these values have yet to be accepted officially by parties to the UNFCCC or by EPA,⁴⁶ they are currently employed by much of the academic literature. The use of AR5 GWP values in LCAs serves to further the convergence between the life-cycle GHG emissions intensities of coal-fired and natural-gas-fired power generation when considering higher fugitive emissions rate scenarios for natural gas systems.

Figure 12 presents the life-cycle GHG emissions estimates for existing coal-fired and natural-gas-fired power plants under the IPCC AR5 GWP values. The figure shows emissions from natural-gas-fired power plants based on several different estimates of FER. Notably, if the FER is close to the 1.15%, as currently estimated by DOE/NETL, the generation of one MWh of electricity in an average U.S. natural-gas-fired combined cycle power plant in 2013 would

⁴³ EPA, "2013 Revisions to the Greenhouse Gas Reporting Rule and Final Confidentiality Determinations for New or Substantially Revised Data Elements," 78 *Federal Register* 71903, November 29, 2013; and Intergovernmental Panel on Climate Change, "Climate Change 2007: The Physical Science Basis," Working Group I Contribution to the Fourth Assessment Report of the IPCC, <http://ipcc.ch/report/ar4/>.

⁴⁴ As recently as November 2013, EPA reported GWP values for methane of 21 over a 100-year time horizon. This value had been accepted by parties to the UNFCCC after being presented in the IPCC *Second Assessment Report 1995* (SAR). EPA's 2012 *Inventory*, released in April 2014 (as well as all prior *Inventories*) used the SAR GWP of 21 for methane. EPA's 2013 *Inventory*, released on April 15, 2015, was the first to use the IPCC AR4 values. Accordingly, methane's comparative role as a GHG has increased by approximately 20% under the new reporting.

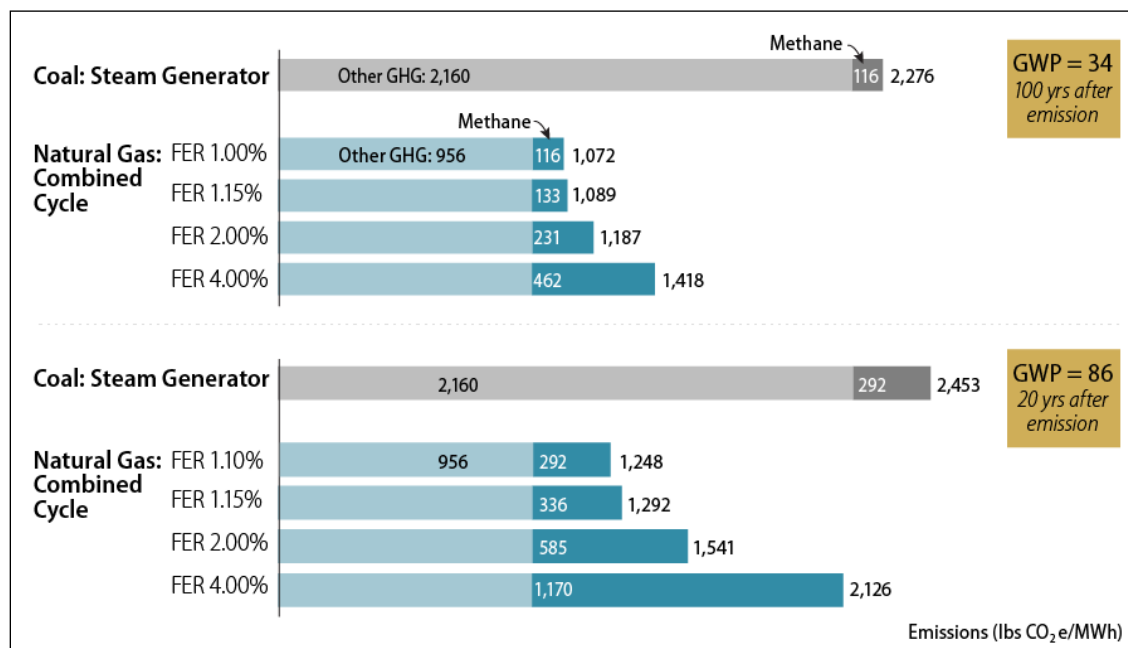
⁴⁵ IPCC, "Climate Change 2013: The Physical Science Basis," Working Group I Contribution to the Fifth Assessment Report of the IPCC, <http://ipcc.ch/report/ar5/>.

⁴⁶ These GWPs include AR5 reported values for methane's indirect effects on aerosols in the atmosphere.

produce approximately 48% of the life-cycle GHG emissions of a coal-fired steam generator when averaged over a 100-year time frame. Conversely, if the FER were in the range of 2%-4%, as estimated by several academic sources, natural gas could produce 63%-87% of the life-cycle GHG emissions of coal when averaged over a 20-year time frame.

Figure 12. Life-Cycle GHG Emissions Estimates with Selected FER, IPCC 2013 GWP

(Emissions in pounds of carbon dioxide equivalents per megawatt-hour of electricity generated)



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Tables D-1 and D-3, pp. D-2-D-6; the U.S. Energy Information Administration, "Annual Electric Generator Report," Form EIA-860, Table 8.2; and Intergovernmental Panel on Climate Change, "Climate Change 2013: The Physical Science Basis," Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.

Notes: Global warming potentials of 34 and 86 for methane (IPCC AR5 2013, 100-year and 20-year, with indirect effects, respectively). The conceptual presentation of these data was introduced in Stefan Schwietzke, "Natural Gas Fugitive Emissions Rates Constrained by Global Atmospheric Methane and Ethane," *Environmental Science and Technology*, vol. 48, no. 14 (2014), pp 7714-7722.

Life-Cycle GHG Emissions Estimates, Full Timelines

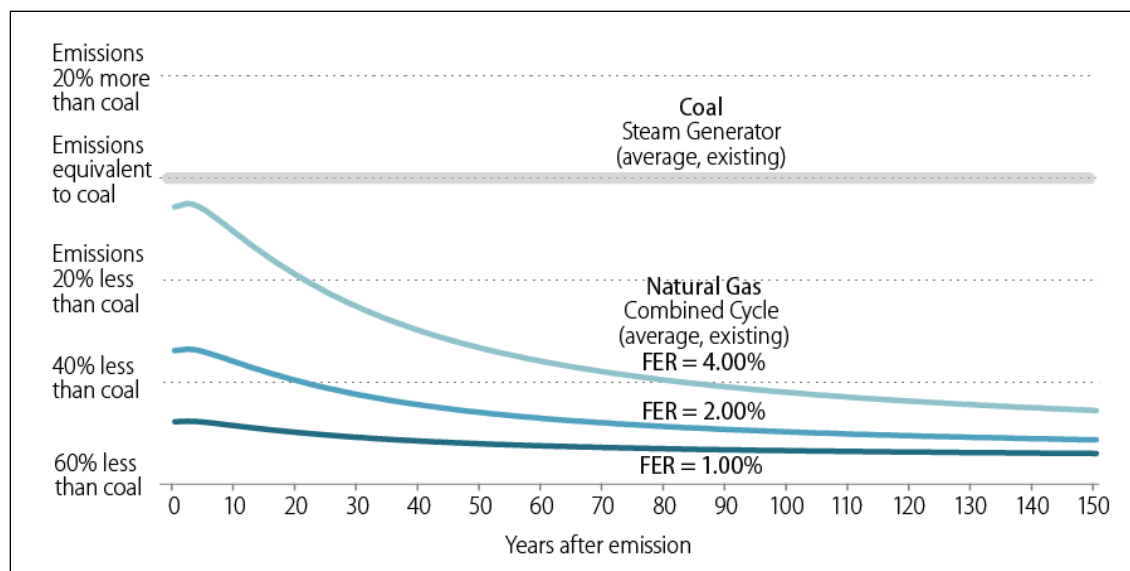
The difference between the estimates—that natural-gas-fired power generation can have 48% of the emissions of coal-fired power generation and 87% of the emissions of coal-fired power generation—is sizeable. This range highlights the importance that assumptions regarding power plant efficiency, FERs, and GWPs have on the life-cycle GHG emissions comparisons among different types of fossil-fuel-fired power plants. To capture a fuller picture of this comparison, **Figure 13** employs a range of variables over a continuous timeline to present life-cycle GHG emissions estimates between existing coal-fired and natural-gas-fired power plants. The figure illustrates that given a FER of around 1.00%, and given GWP values from IPCC AR4, the generation of one MWh of electricity in an average U.S. natural-gas-fired power plant in 2013 would produce approximately 50% of the life-cycle GHG emissions of a coal-fired steam generator across the entire time frame for which it would be measured. However, if the FER were in the range of 2%-4%, as estimated by some academic sources, the impacts of life-cycle

emissions from natural-gas-fired power generation could be comparable to coal-fired power generation initially (within 5%-35%) and could remain within range of the coal plant's life-cycle emissions over the first 20 years after the emissions (within 20%-40%).

The analysis in **Figure 13** would be applicable for policy discussions regarding fuel-switching strategies from coal to natural gas in the existing fleet of U.S. power generators (e.g., similar to potential actions under EPA's proposed GHG emissions standards for existing power plants (EPA's Clean Power Plan)).⁴⁷

Figure 13. Comparison of Existing Power Plants with Selected FER, IPCC 2007 GWP

(Life-cycle emissions values in percentages, indexed against Coal: Steam Generator (average, existing))



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Tables D-1 and D-3, pp. D-2-D-6; U.S. Energy Information Administration, "Annual Electric Generator Report," Form EIA-860, Table 8.2; and Intergovernmental Panel on Climate Change, "Climate Change 2007: The Physical Science Basis," Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change.

Notes: The conceptual presentation of these data was introduced in Ramón A. Alvarez et al., "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure," *Proceedings of the National Academy of Sciences*, vol. 109, no. 17 (April 24, 2012). Alvarez et al. illustrates several fuel-switching option rates; **Figure 13** is analogous with the option "converted fleet."

Some stakeholders contend that another relevant metric for comparing natural-gas-fired and coal-fired power generation would be to examine the life-cycle GHG emissions intensities of new, advanced power plant models. **Figure 14** presents the life-cycle GHG emissions estimates between the most efficient, advanced coal-fired power plant model and the most efficient, advanced natural-gas-fired power plant model (from **Table 1**) using IPCC AR5 GWP values. The figure illustrates that given a FER of around 1.00%, life-cycle GHG emissions from the generation of one MWh of electricity in an advanced natural-gas-fired power plant model would begin approximately 35% lower than a coal-fired model in the short term and improve to

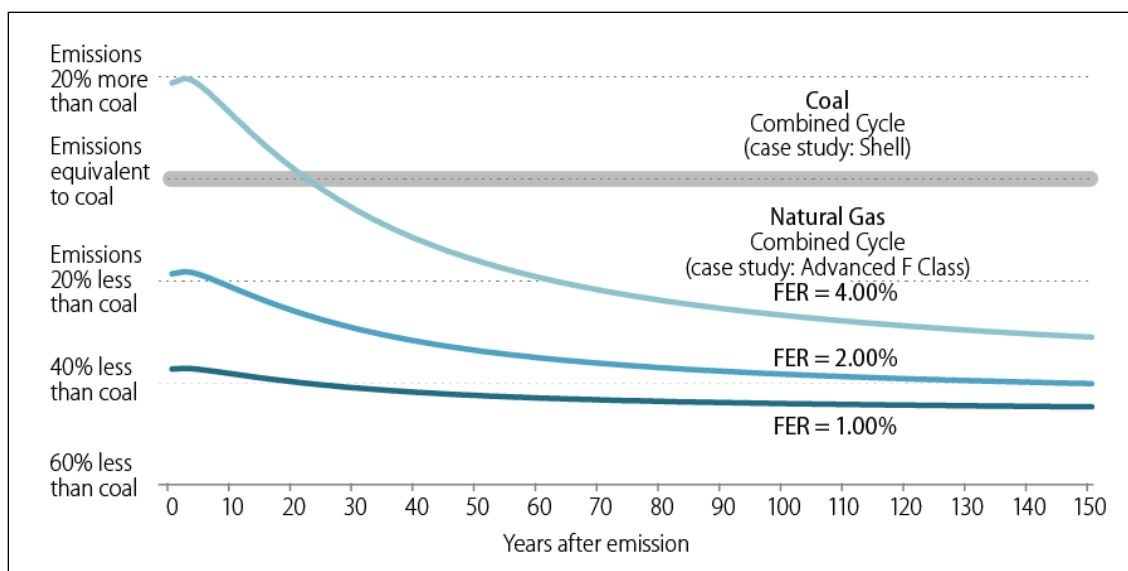
⁴⁷ EPA, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Proposed Rule," 79 *Federal Register* 34830, June 18, 2014. For more on the Clean Power Plan, see CRS Report R43572, *EPA's Proposed Greenhouse Gas Regulations for Existing Power Plants: Frequently Asked Questions*, by James E. McCarthy et al.

approximately 45% lower in the long term. Further, if the FER were in the range of 2%-4%, as estimated by some academic sources, the impacts of life-cycle emissions from advanced natural-gas-fired power generation could be near or greater than advanced coal-fired power generation initially (from 20% less to 20% greater) and could remain within range of the advanced coal plant's life-cycle emissions over the first 60 years after the emissions (within 20%-35%).

The analysis in **Figure 14** would be applicable for policy discussions regarding fuel use choices for new, or significantly modified, power plant construction.

Figure 14. Comparison of Advanced Power Plants with Selected FER, IPCC 2013 GWP

(Life-cycle emissions values in percentages, indexed against Coal: Combined Cycle (case study: Shell))



Source: Congressional Research Service, with data from U.S. Department of Energy, National Energy Technology Laboratory, "Life Cycle Analysis of Natural Gas Extraction and Power Generation," DOE/NETL-2014/1646, May 29, 2014, Tables D-1 and D-3, pp. D-2-D-6; U.S. Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," Revision 2a, September 2013, Revision 2, November 2010, DOE/NETL-2010/1397, Exhibit ES-2, p. 5; and Intergovernmental Panel on Climate Change, "Climate Change 2013: The Physical Science Basis," Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.

Notes: Conceptual presentation of data from Ramón A. Alvarez et al., "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure," *Proceedings of the National Academy of Sciences*, vol. 109, no. 17 (April 24, 2012). Alvarez et al. illustrates several fuel-switching option rates; **Figure 14** is analogous with the option "converted fleet."

Concluding Remarks

In debates about energy policy, many assert that natural gas has approximately half the CO₂ emissions of other fossil fuels. While this statement is accurate in some cases and under certain conditions, it is not complete. The net climate impact of replacing other fossil fuels with natural gas depends upon a number of analytic choices, including the following:

- The fuel being replaced (e.g., coal, fuel oil, gasoline, diesel),
- The end-use sector (e.g., electricity generation, transportation, home heating),

- The equipment or facility within the sector (e.g., all existing power plants, only the least efficient existing power plants, new power plant configurations),
- The rate and extent to which a sector will be converted,
- The time period over which the impacts will be estimated,
- The fuel cycle (e.g., combustion cycle, production cycle, “cradle-to-grave”) and specific production processes modeled (e.g., conventional vertical wells, hydraulically fractured horizontal wells), and
- The GHGs modeled (e.g., CO₂, methane, nitrous oxide).

Summary of Results

Analyzing the fullest practicable range of these choices and using the best available data and scientific understanding, the following results are reported:

- Comparisons of the life-cycle GHG emissions intensities for natural-gas-fired and coal-fired power generation are sensitive to each assessment’s reported data as well as the choice of boundaries and input parameters. In some cases, the accuracy of data is as uncertain as it is significant.
- Natural gas combustion, on a per-unit-of-energy basis, produces approximately 56% of the CO₂ emissions of coal.
- Natural gas, when combusted at different types of existing U.S. power plants, produces anywhere from 42% to 63% of the CO₂ emissions of coal, depending upon the power plant technology.
- However, in order to more fully assess the climate impacts of a fuel employed in the power sector, analyses aim to aggregate emissions across the entire supply and utilization chain (i.e., from extraction to end use). Such analyses are referred to as life-cycle assessments (LCAs).
- Due to its potency as a GHG, methane lost to the atmosphere during the production and transport of fossil fuels can greatly impact the life-cycle GHG emissions estimates for power generation. DOE and EPA currently estimate a FER of around 1% in natural gas systems; a number of academic studies estimate FERs in the range of 2%-4%. Estimates for coal production are similarly uncertain.
- Further, due to its chemical composition, methane’s climate impacts are significantly more pronounced in the short term as compared to the long term.
- Thus, when considering existing power plants, a natural-gas-fired combined cycle power plant produces approximately 50% of the life-cycle GHG emissions of a coal-fired steam generator, both in the short and the long terms, given a FER of around 1% in natural gas systems.
- However, when considering other existing natural-gas-fired technologies (e.g. single cycle), or advanced technologies, the comparative life-cycle emissions benefits of natural gas are reduced.
- Further, when considering the possibility of higher fugitive emissions rates for natural gas production and transport activities (e.g., 2%-4%), the life-cycle GHG emissions of existing natural-gas-fired technology could be comparable to coal-fired power generation initially (within 5%-35%) and could remain within range

- of the coal plant's life-cycle emissions over the first 20 after the emissions (within 20%-40%).
- Similarly, when comparing advanced power plants under the possibility of higher fugitive emissions rates (e.g., 2%-4%), the life-cycle GHG emissions of natural-gas-fired technology could be near or greater than coal-fired power generation initially (from 20% less to 20% greater) and could remain within range of the coal plant's life-cycle emissions over the first 60 years after the emissions (within 20%-35%).

Policy Considerations

The results illustrate that the choices made in power generation regarding supply chains, production technologies, and consumption patterns can impact a fuel's life-cycle GHG emissions in ways both large and small. For this reason, LCA has become an important decision-support tool that has been used to identify the most effective improvement strategies and avoid "burden shifting" from one activity or sector to another.⁴⁸ Given the results, several points of interest emerge for the consideration of future policy:

- Natural gas resources and technologies are not homogenous. Neither are coal's. The choice of fuel resources, fuel extraction processes, transport options, and power plant technologies for both coal and natural gas returns significant differences in life-cycle GHG emissions estimates. Effective policy considerations would require appropriate specificity and detail.
- Due to its potency as a GHG, the amount of methane lost to the atmosphere during the production and transport of fossil fuels can greatly impact the life-cycle GHG emissions estimates for power generation. In order to fully understand the climate implications of switching from coal to natural gas in the domestic power sector, improvements are required in the measurement and validation of emissions inventories (i.e., for both coal production and natural gas production). Effective policy considerations would require strategies to attain these inventory improvements.
- Further, in order to most fully realize the climate benefits of switching from coal to natural gas in the domestic power sector, a FER of approximately 1% is required from natural gas systems. Studies have shown that cost-effective technologies exist to mitigate fugitive emissions from some activities in the natural gas supply chain.⁴⁹ Additionally, EPA has recently finalized performance standards for the oil and natural gas sector that may serve to reduce fugitive emissions.⁵⁰ Effective policy considerations would require strategies to attain and/or maintain these targeted emissions rates.

⁴⁸ "Burden shifting" implies a situation where the impacts of emissions are minimized at one stage of the life-cycle in one geographic region or in one particular impact category but are increased elsewhere, perhaps unrecognized.

⁴⁹ For examples, see ICF International, "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries," prepared for the Environmental Defense Fund, March 2014, http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf; and Susan Harvey, "Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste," prepared for the Natural Resources Defense Council, March 2012, <http://www.nrdc.org/energy/files/Leaking-Profits-report.pdf>.

⁵⁰ EPA, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012. The rulemaking took full

- Given methane's unique characteristics as a GHG (e.g., its short-term potency compared to CO₂), effective policy considerations would require an analysis of both the short-term and the long-term climate implications of a fuel's life-cycle GHG emissions. The analysis would likely spur debate over the proper weight to place on both short- and long-term assessments of the costs and benefits of fuel-switching strategies.
- This report compares the life-cycle GHG emissions between coal and natural gas in the domestic power sector. It does not analyze other fuel-switching strategies that support natural gas (e.g., from coal-fired electricity to distributed natural gas in the home heating sector, from petroleum products to compressed natural gas in the domestic transportation sector,⁵¹ or from regional coal to imported liquefied natural gas in international markets⁵²). These other scenarios would require different analytic inputs and wholly separate assessments. Effective policy considerations would require data and analysis with the appropriate LCAs.
- This report compares the life-cycle GHG emissions between coal and natural gas in the domestic power sector. It does not analyze other energy options. A full assessment of the climate implications of fuel-switching strategies in the domestic power sector would require a series of LCAs for the full range of energy options, including other fossil fuels and their derivatives, as well as biofuels, biomass, hydropower, nuclear, geothermal, solar, wind, and other renewables.
- This report compares the life-cycle GHG emissions between coal and natural gas in the domestic power sector. It does not analyze the net benefits of natural gas to the general economy (i.e., inclusive of jobs, investments, infrastructure, national security, human health, safety, and other environmental impacts). A full assessment of the costs and benefits of fuel-switching strategies would demand an integrated analysis across all issues.

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effect on January 1, 2015. Further, EPA has stated its intent to strengthen these standards. See Executive Office of the President, "FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions," press release, January 14, 2015, <https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1>. Conversely, no federal standards exist to control fugitive emissions from coal production and transport activities, and EPA has denied petitions to do so in the past. See EPA, "Notice of Final Action on Petition from Earthjustice to List Coal Mines as a Source Category and to Regulate Air Emissions from Coal Mines," 78 *Federal Register* 26739, May 8, 2013.

⁵¹ For an example of an LCA for the heavy-duty truck sector, see Jonathan R. Camuzeaux, et al., "Influence of Methane Emissions and Vehicle Efficiency on the Climate Implications of Heavy-Duty Natural Gas Trucks," *Environmental Science and Technology*, vol. 49, no. 11 (2015), pp 6402–6410, <http://pubs.acs.org/doi/abs/10.1021/acs.est.5b00412>.

⁵² For an example of an LCA for liquefied natural gas exports, see DOE/NETL, "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States," May 29, 2014, DOE/NETL-2014/1649, <http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Life%20Cycle%20Analysis/NETL-LNG-LCA-29May2014.pdf>.

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